A Novel Hierarchical Contribution Factor based Model for Distribution Use-of-System Charges

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***Abstract*— Due to the limited visibility at low voltage (LV) networks, existing Distribution Use-of-System (DUoS) charging methodologies assume that all the network users use the network in proportion to their peak flows. This naive supposition fails to reflect the contribution of network users to network peak flows, which actually is the driver for network reinforcement. This can send an inadvertent signal to customers, leading to aggravated network pressure. This paper for the first time, brings the new dimension into the design of DUoS charging methodology by considering the true contribution of customer class's load on network peak flows. It proposes a novel Hierarchical Contribution Factor based Model (HCM), recognizing the contributions of differing customer classes to the network reinforcement of upstream asset. Such contribution will be further propagated to network assets at higher voltage level, forming a Hierarchical CF model and reflecting the true individual class contribution to the whole-system reinforcement. Benefit of the proposed model on investment deferral is assessed by determining annuitized present value (PV) of future investments, and consequences are assessed on a 22-bus practical Indian reference network. The approach helps customers as a class to reduce their network usage charges by minimizing their energy usage contribution during distribution network peaks, eventually reducing distribution network investment and energy transfer costs.**

***Keywords*—Contribution factor, Demand Side Response, Distribution Use-of-System Charges, Long-term Incremental Cost, LV Networks, Energy Economics**

I. Introduction

The UK government has set an ambitious target to transit towards a low carbon energy future by reducing carbon emission and increasing renewable energy [1-3]. Year 2015 has witnessed £3.5bn annual subsidies in the UK just for photovoltaic (PV) installations. With the increasing number of low carbon energy technologies (such as PV, electric vehicles, battery storage and heat pumps) being connected to the edge of the grid, power distribution networks will have unprecedented complexity and uncertainty [4-9]. Load estimation at various network nodes is becoming a challenging task for the utilities in such a situation [10]. Currently, the default solution to this issue is passive network reinforcement, which will finally be paid from customers' rising energy bills. In order to accommodate the large influx of low carbon energy technologies without passing extra economic burden to customers, it is critical to design innovative technical and commercial solutions to guide the planning and operation of end-customers [11-16].

Network planning methodologies aim to model the actual network, while considering some assumptions to make for data deficit and unknown future variations. For this methodology, considered modelling may not be a true reflection of network and the overall formulation of network cost. Further, optimisation algorithms may not guarantee global optima, as it would depend on the accuracy of assumed parameters. Such methodologies may lead to erroneous solutions, despite adopting the best of optimisation algorithms and well thought out assumptions. In contrast to the use of optimisation algorithms, use of network pricing involves consideration of few basic assumptions. A robust and thoughtful pricing model would offer an appropriate signal to the user, who would respond to the economic signal by way of optimal location and utilisation, such that its network utilisation is minimized. This would eventually lead to low requirement of network reinforcement, thus minimizing network investment required to meet the specified load.

Distribution Use-of-System (DUoS) charges is an effective commercial tool for distribution network operators (DNOs) to guide new network users in a deregulated power market. The aims of DUoS charges are twofold: i) to recover reinforcement cost for the distribution network operators (DNOs) based on an economic pricing model; ii) to reflect industry regulation as a whole and to offer an efficient economic signal to the users. According to the energy market regulator in the UK, an ideal DUoS charging model should accurately reflect forward-looking costs, incentivise efficient usage and development of the system, and incorporate the generation use of system charges (GDUoS) [17].

A significant amount of research on DUoS model has been reported from industry and academia. The Distribution Reinforcement Model (DRM), a Postage Stamp method, was traditionally used by the UK industry, which allocates all the network cost to customers only according to the voltage level connected. DRM provides no locational signals or ex-ante cost information to customers [18]. It offers no guidance for the planning of distributed generators (DG's) [19]. DRM's weakness was rectified in many new models proposed by academia. Location is considered as the key factor in most of these models by charging against the critical power flow scenarios, network congestion and power losses [20]. Investment Cost Related pricing (ICRP) was proposed to not only recover the historical investment, but more importantly to evaluate the impact of future incremental cost placed on the system, as a result of new load or generation being added at any point on the distribution network [21-22]. Long Run Incremental Cost Pricing (LRIC) model considers utilisation rate of an asset in addition to distance [23-24]. This approach is recognized as an economically efficient approach for allocating distribution network cost, as it determines network charges as the difference in the present value of future investment, consequent upon nodal power perturbation for generation or demand. Further the impacts of network security, contingencies, and reliability have been integrated into the LRIC pricing approach [25-28]. The integration of DG is considered using DUoS price as a signal to encourage DG connection at the appropriate location [29]. The interaction of generation and demand in the distribution network is investigated by nodal pricing, contract pricing and value-based pricing [30-32]. The uncertainty introduced by DG is also considered in the network reinforcement and charging methodology [33-34]. Demand response plays a major role in demand reduction and demand shifting, and dynamic pricing models can effectively consider the same [35-38].

Existing DUoS methodologies have covered many attributes of an ideal model, considering factors like forward-looking cost, distance, location, utilisation rate, reliability, and generation technology. Traditional methods assume that all customers consume energy in a similar way within a distribution network and follow the aggregated load profile. However, end-users actually consume energy in diverse manners and thus have different contribution to the networks' reinforcement. Likewise, the downstream assets contribute differently to the upstream assets, based on the coincidence level of the load profiles. The industry has attempted to address the issue by introducing a diversity factor, which is defined as the ratio of maximum demand at the substation to the sum of the maximum demand at all points of the immediate lower distribution network served by that substation. However, this factor aims to calculate the after-diversity peak load to evaluate the reinforcement cost, instead of accurately allocating such cost to individual customers [39]. In order to send customer-tailored signals to effectively guide individual's energy behavior, it is critical to develop a new DUoS model considering the additional dimension of energy consumption pattern variations among customers.

This work develops a novel customer-specific DUoS charging model based on a hierarchical contribution model (HCM), which distinguishes between different customer class contributions to the distribution network and all the way to the upstream assets. As a first, this considers customer class's contribution to network peak flow, instead of considering customer class's peak flow, which may occur at a different time. A novel concept of CF is proposed to evaluate contributions at two levels: i) contribution of total load connected at any node to each upstream shared asset, and ii) contribution of customer class to total load connected at any node. Based on this HCM model, the customer-specific DUoS charging model is implemented using basic LRIC approach. The proposed approach encourages various customer classes to modify their distribution network usage pattern to minimize network peaks, thus delaying network investment. The ultimate goal of proposed pricing scheme is to offer a customer class specific pricing signal to distribution network users, which incorporates CF to highlight users' contribution to network peak conditions, in addition to location based signal. Main contributions of this paper are summarized as follows:

i) A novel hierarchical contribution model based on CF in order to reflect actual propagation of the key reinforcement driver within a distribution network.

ii) It considers the contribution of customer class load to network peak, rather than merely considering peak flow of a customer class, thus reflecting the true impact of customer class load on network reinforcement requirement.

iii) For the first time proposes a usage-based pricing signal to customer classes in addition to locational signal, directly encouraging them to modify their usage pattern in response to changed distribution network prices.

The research could make significant impact to the efficient planning and operation of DNOs in a low carbon environment, offering individual charges to customer class, considering their specific class characteristics. Lower distribution network charges can be offered for customer classes not expected to contribute to system peak, with their peak demand differing significantly from system peak demand characteristics. These charges attract customers with characteristics favorable for distribution network development at specific locations. Such charges would make the system efficient; utilities may delay network reinforcements, investments in new generation units, and network infrastructure [40-41]. LRIC pricing is a well-established approach to evaluate long term distribution network charges for UK distribution networks, assuming that network reinforcement would be required when the loading level of circuit reaches its capacity. Hence proposed HCM based approach to offer customer class specific signal is implemented using LRIC as the base approach. However, the HCM approach is equally applicable to other DUoS charging methodologies.

The rest of the paper is organized as follows: Section II gives a description of HCM based DUoS charging methodology. Section III discusses the test case system and analyses the results from proposed and traditional models. Finally, Section IV concludes the work contribution.

II. Hierarchical Contribution Model Based DUoS Charging Methodology

The proposed HCM based charging mechanism illustrated in Fig. 1 shows the algorithm for calculating customer class specific DUoS charges. This integrates the reflection of different customer class contributions to distribution network peak demand for network charging. The contributions are determined using CF, based on which coincident demand is calculated. CF is incorporated at two levels to reflect user’s actual network usage. First, the contribution of total load connected at any node to each upstream shared asset is considered using load-to-asset contribution factor (LACF). Based on this LACF, unit charges are computed at all nodes. Second, the contribution of customer class to the total load connected to that node is determined using class-to-load contribution factor (CLCF). DUoS charges from the proposed model are evaluated for various customer classes connected to the network. Outline of the proposed model is as follows:

1. Use input system data to evaluate LACF and CLCF.
2. Obtain coincident demand from LACF.
3. Use these demand to perform power flow analysis. Evaluate time horizon and present value (PV) of future reinforcement, with and without nodal injections.
4. With this change in PV of future reinforcement, obtain unit charges.

5. Use unit charges and CLCF to compute total DUoS charges for various classes of customers.

6. Calculate benefit of the new model through the annuitized PV of future reinforcement cost.

Flowchart of Fig. 1 describes the proposed model for evaluating customer class specific charges. Input system data, *i.e.* sub-class profile, upstream asset profile, and total load profile at the node, is used to evaluate LACF and CLCF. Coincident demand are computed from LACF and further used to calculate power flow through network asset. When the capacity of any network component is fully utilized, it needs to be reinforced in the upcoming future. This enhancement is known as future reinforcement in the network, over a given planning horizon. Base case and incremental case load flows are run to compute time horizon required for future network asset reinforcement. Base case power flow analysis determines network utilisation under normal demand/generation condition, whereas incremental case power flow analysis determines the effect of demand/generation change at the study node. Then PV of future reinforcement is calculated with and without nodal injections for all customer classes. Further, annualized incremental cost of components is evaluated for all customer classes at the connection node. Aggregating the annualized incremental cost of components for all customer classes, unit charges are obtained. CLCF and unit charges are used to compute customer class specific charges. CF considered at two levels helps to determine the effective contribution of customer class on distribution network asset peak usage and reinforcement costs.

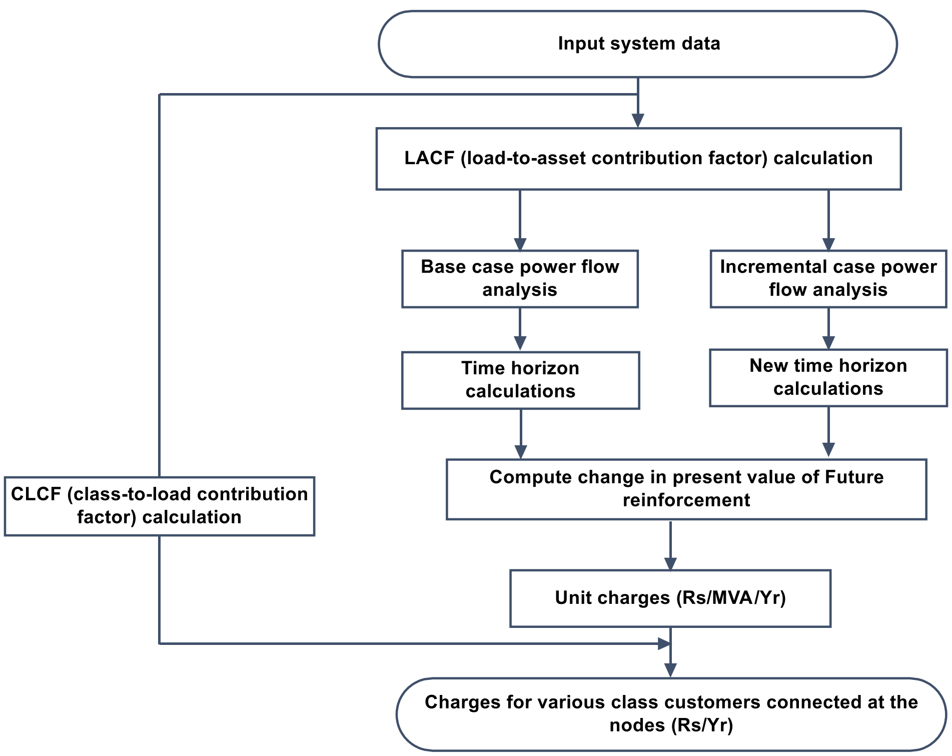


Fig. 1. Flow chart for Hierarchical Contribution Model

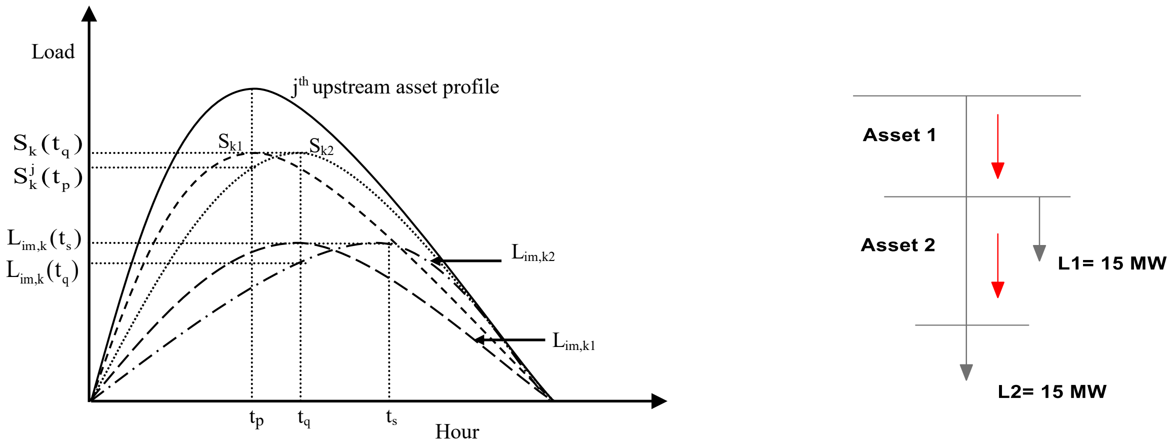


Fig. 2. (a) Load profile at different network levels (b) Simple 3-bus bar network

The concept and impact of HCM approach can be highlighted using Fig. 2 (a). This figure represents multiple load profiles at different distribution network levels. S_{k1} and S_{k2} are two possible profiles of total load at the node k. k is the index of nodes. Traditional LRIC model evaluates charges for usage of j^{th} asset based on peak profile at k^{th} node. j is the index of upstream assets. Since the peaks of both profiles are same, traditional model does not differentiate between the impacts of two profiles on network charges. Proposed HCM approach uses LACF to evaluate the contribution of load at node k, at the time of peak occurrence at the upstream asset j. Node k's contribution to upstream asset's peak is equal to $S_k^j(t_p)$ for profile S_{k2}, where t_p is the time of peak load occurrence of upstream asset j. This would result in higher charges for S_{k1}, as compared to a relatively lower charge for S_{k2}, despite their peaks being similar. This appropriately reflects the contribution of each profile to asset reinforcement, and signals the user of the profile S_{k1} to shift towards profile S_{k2}. Similarly, $L_{im,k1}$ and $L_{im,k2}$ are two possible load profiles of customer sub-class i of customer class m supplying node k. Here, m and i are the indices of customer classes and sub-classes respectively. CLCF is contribution factor from customer sub-class i of customer class m, to total load at node k, during the occurrence of peak at node k. The contribution of sub-class's load to total load's peak is equal to $L_{im,k}(t_q)$ for profile $L_{im,k2}$, where t_q is the time of total load's peak occurrence at node k. This results in higher charges for $L_{im,k1}$ and lower charges for $L_{im,k2}$, despite their peaks being equal. This encourages user with $L_{im,k1}$ profile to shift towards profile $L_{im,k2}$, to reduce its contribution to peak of S_{k2}. This CLCF consideration reduces peak of total load at node k, thus reducing upstream asset peak. CLCF calculation is independent from load flow analysis and is calculated from the existing load profile scenario of customer sub-classes and total load connected at any node.

The proposed approach is highlighted using a 3-node network illustrated in Fig. 2 (b). In reference to Fig. 2 (a), S_{k1} and S_{k2} are two possible profiles of load L2. $L_{im,k1}$ and $L_{im,k2}$ are two possible load profiles of customer sub-class i of customer class m of load connected at load L2. Load L1 is supplied by asset 1 while load L2 is supplied by two networks, identified as asset 1 and asset 2. Value of loads L1 and L2 is 15 MW each. The two assets are assumed to be identical, each having a capacity of 45 MW, with an overall cost of Rs. 1000. Power flows are shown with red arrows. For this scenario, asset 2 supplies power only to load L2, hence has a power flow of 15 MW. Asset 1 supplies power to both loads L1 and L2, hence has a power flow of 30 MW.

For illustration, charges are calculated for load L2 only. To evaluate unit charges with proposed approach, it is assumed that load-to-upstream shared asset contribution factor (LACF) for load L2 to upstream shared asset *i.e.* asset 1, is 0.80. Asset 1 is the shared asset while asset 2 is the individual asset for this load, so LACF for asset 2 would always be 1. With this, coincident demand of load 2 to asset 1 comes out to be 12 MW. With the consideration of coincident demand, power flows through asset 1 and asset 2 will be 27 MW and 15 MW, respectively. From the power flows, time horizons for future reinforcement of asset are evaluated with and without 0.1 MW increment in load L2. The value of these time horizons for asset 1 and asset 2 are 31.94 and 32.18 (in Years) respectively. Then change in present value is evaluated from these time horizons, which further gives unit charges. Unit charges for L2 node is 0.0346 Rs/MW/Yr.

Further, it is assumed that load L2 consists of A, B, C, and D classes, having 30%, 40%, 20%, and 10% share in peak load at the connection node respectively. Class-to-load contribution factor (CLCF) for A, B, C, and D classes is presumed to be 0.5, 0.8, 0.6, and 0.7, respectively. With the unit charges and CLCF, total distribution-use-of system charges would be 0.078, 0.166, 0.062, and 0.036 (all in Rs/Yr) for the four customer classes respectively.

A mathematical formulation reflecting the above discussed concept and flowchart has been developed hence.

A. Coincident demand calculations for each upstream asset

From the load profile data available at various nodes, coincident demand of total load connected to any node k, to peak of upstream asset j, is calculated using load-to-asset CF. This factor is calculated as

$$\mathrm{LACF}_{kj} = \frac{S_k^j(t_p)}{S_k(t_q)} \tag{1}$$

where $S_k = [S_k(t_1), S_k(t_2), \cdots$ is the total load at node k for different times t; $t = [t_1, t_2, \cdots$ is the time moment of daily load profile; $S_k^j(t_p)$ is the total load at node k at p^{th} time instant t_p which is the time of peak loading of an upstream asset j connected above node k; $S_k(t_q)$ is the total load connected at node k at time instant t_q which is the time of total load's peak at node k; LACF_{kj} is the contribution of total load connected at any load point k to any of its upstream asset j; k is index of network nodes; and j is index of upstream assets feeding node k from load point to grid supply point. Here, j may or may not be an immediate upstream asset of node k.

From these LACF, coincident demand of load at node k to each upstream shared asset j, *i.e.* CD_{kj} is evaluated as

$$CD_{kj} = LACF_{kj} * S_k^{Rated} \tag{2}$$

where S_k^{Rated} is the rated load connected at node k.

B. Unit charges

Coincident demand calculated from (2) is used as input power flow data to assess actual asset usage. Distribution network asset needs reinforcement when its loading level approaches its capacity. So time horizon required for future reinforcement can be evaluated from current loading and capacity of network asset. Distribution network asset j supplying node k has power carrying capacity C_{kj} and supports power flow P_{kj}. Load growth rate for sub-class i of customer class m is assumed as r_{im}. Time horizon, in years, required to reinforce network asset j due to load growth in sub-class i of customer class m connected at node k is given by

$$n_{im,kj} = \frac{\log C_{kj} - \log P_{kj}}{\log(1 + r_{im})} \tag{3}$$

LRIC charges are evaluated by reviewing the present value of future reinforcement cost, PV with and without the load increment. The future investment can be discounted back to its present value. For a discount rate d, PV of future investment in network asset j is determined for sub-class i of customer class m connected at node k as

$$PV_{im,kj} = \frac{AC_j}{(1 + d)^{n_{im,kj}}} \tag{4}$$

where AC_j is modern equivalent asset cost of network asset j. PV of future investment is determined by discounting the modern equivalent asset cost to its present value.

PV with nodal increment is evaluated considering new time horizon for future reinforcement. Power flow along the associated network assets j is altered by ΔP_{kj} due to nodal injection by customer sub-class i of customer class m supplying node k. The new time horizon for reinforcement of asset j is

$$n_{im,kj}^{new} = \frac{\log C_{kj} - \log(P_{kj} + \Delta P_{kj})}{\log(1 + r_{im})} \tag{5}$$

This in turn affects PV of future investment in network asset j for sub-class i of customer class m connected at node k

$$PV_{im,kj}^{new} = \frac{AC_j}{(1 + d)^{n_{im,kj}^{new}}} \tag{6}$$

As a result of nodal injection, change in PV for an asset j for sub-class i of customer class m connected at node k is

$$\begin{aligned}\Delta PV_{im,kj} &= PV_{im,kj}^{new} - PV_{im,kj} \\ &= AC_j \times \left(\frac{1}{(1+d)^{n_{im,kj}^{new}}} - \frac{1}{(1+d)^{n_{im,kj}}} \right)\end{aligned} \tag{7}$$

Annuitized unit incremental cost for network asset j, due to sub-class i of customer class m connected at node k is

$$IC_{im,kj} = \frac{\Delta PV_{im,kj} * AF}{C_{kj}} \tag{8}$$

where AF is the annuity factor .

Long-run incremental cost to support node k is summation of annuitized incremental cost over all assets j by all customer classes over that node, and is given by

$$LRIC_k = \frac{\sum_{j,im} IC_{im,kj}}{\Delta D_k} \tag{9}$$

where ΔD_k is the overall power injection at node k . From (9), unit charges in (Rs/MVA/Yr) at the node k are obtained.

C. Charges for various customer classes at the nodes

After calculating unit charges, total charges are calculated for sub-class i of customer class m , considering that CF reflects class customer's contribution to the peak of a total load connected at a node k .This class-to-load CF is

$$CLCF_{im,k} = \frac{L_{im,k}(t_q)}{L_{im,k}(t_s)} \tag{10}$$

where $L_{im,k} = [L_{im,k}(t_1), L_{im,k}(t_2), \cdots \ldots_n)]$ is the load of sub-class i of a customer class m connected at node k during time t ; $t = [t_1, t_2, \cdots$ is the time interval of daily load profile; $L_{im,k}(t_q)$ is the load of sub-class i of a customer class m at q^{th} time instant t_q which is the time of total load's peak at node k ; $L_{im,k}(t_s)$ is the load of sub-class i of customer class m connected at node k at time instant t_s which is the time of peak load occurrence of sub-class i , $CLCF_{im,k}$ is the contribution from customer sub-class i of class m to peak of total load at node k .

Charges for customer sub-class i of class m , reflecting its contribution to peak of total load connected at node k is

$$TLC_{im,k} = LRIC_k * CLCF_{im,k} * L_{im,k}^{Rated} \tag{11}$$

where $TLC_{im,k}$ is the total DUoS charges for customer sub-class i of customer class m at node k and $L_{im,k}^{Rated}$ is the rated load of customer sub-class i of customer class m at node k .These charges reflect contributions of various customer classes to network peak. Hence, total DUoS charges are calculated for various customer classes from (11).

D. Investment deferral

PV of future investment for asset j supplying node k is obtained from the proposed model. This is evaluated using $PV_{im,kj}$ obtained from (4).

$$PV_{kj} = \sum_{i,m} PV_{im,kj} \tag{12}$$

Benefit of the proposed model can be assessed in terms of the difference in annuitized PV of future reinforcement cost of network assets, defined here as ΔPV. Mathematically this can be evaluated for the whole system as

$$\Delta PV = \sum_{k,j} (PV_{kj}^{old} - PV_{kj}) * AF \tag{13}$$

where PV_{kj}^{old} is PV of future investment for asset j supplying node k, evaluated from basic LRIC model [23].

III. Results and Analysis

A. System Description

Efficiency evaluation of any network pricing methodology requires modelling of the network. Considering the large network size and the quantum of data to be handled, network pricing analysis could become a complex and challenging task. This necessitates reducing large practical networks into smaller representative networks, called reference networks. The proposed model is applied to a part of practical Indian reference network. Reference network was formed with practical data available for Jodhpur district, located in the Rajasthan State of Northern India, for the months of October and November in 2007. The network has four voltage levels, 220 kV, 132kV, 33kV and 11kV, consisting of 22 buses, 11 transformers, 10 distribution lines and 11 load points, as shown in Fig. 3. These are considered to be a part of distribution networks, where the power flows are usually radial and contribute to a specified distribution network area only. Each load point comprises of various class users, viz. General, Industrial, Agricultural and Water-Works. General class users represent group of Domestic, Non-Domestic, Public Street Lighting and Mixed Load customers. Similarly, Metered Agricultural, Flat Rate Agricultural and Agricultural Nursery comprise of Agricultural class, while Small Industrial, Medium Industrial, and High Tension Industrial are grouped into Industrial class. Water-Works consists of all type of Water-Works connections for supplying water pumping stations [42].

Profile of total load connected at various nodes is shown in Fig. 4. This profile is sufficiently different from various customer class and sub-class profiles of customers connected at these nodes. This diversity in load profile is represented by considering each customer class to be classified into customer sub-classes, representing the capacity up-to which connection can be offered to various customers of that class. The general class comprises of three sub-classes with capacities 1 kW, 2 kW, and 5 kW. Industrial, Agricultural and Water-Works classes comprise of two sub-classes with capacities 17 kW & 50 kW, 7 kW & 25 kW and 5 kW & 15 kW respectively. With a consideration of total load profile at various nodes, a representative average load profile for every sub-class over the preceding year is assumed to represent its network usage characteristics. Peak demand of these profiles is used to evaluate the contribution of different sub-classes to peak load at the connection node. Customer sub classes of a certain class are presumed to have similar load profiles and their response to price signals is presumed to be convergent. The cost of all transforming assets (T1, T2, …T11) and line assets (D1, D2, … D10) is to be allocated between customers of all sub-classes connected at load points (L1, L2, … L11).

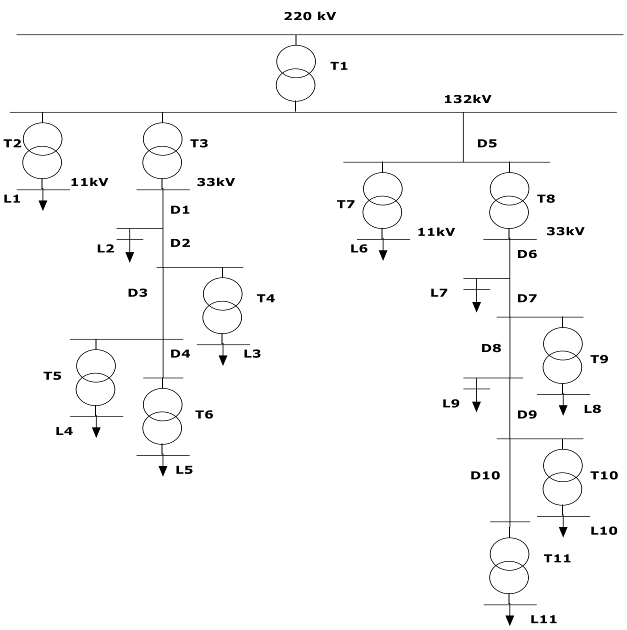


Fig. 3. 22- bus practical Indian network [42]

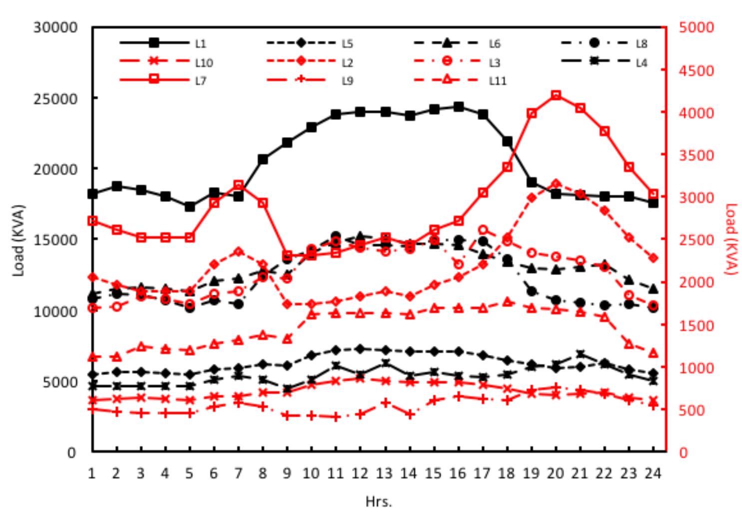


Fig. 4. Total load profile at various nodes

B. HCM based DUoS charges implementation

This section discusses the customer class specific charges based on HCM for the Indian reference network, obtained from the proposed model. Coincident demand to each upstream asset is calculated for the demand at each node, using its load profile. First, LACF's are calculated at the nodes from (1). CF's for loads at various nodes, to each upstream shared asset are shown in Table I. As seen in Table I, loads L1 and L8 dominate in the usage of asset T1, while L2 and L7 have the lowest contribution to T1 usage. Also, L7 has lowest contribution to the usage of asset D5 and L8 dominates usage of asset D5. Similarly, contribution of other loads can be visualized for their usage contribution of assets supplying them power.

TABLE I

CONTRIBUTION FACTOR OF LOAD TO EACH UPSTREAM SHARED ASSET (LACF)

Nodes	**T1**	**T3**	**D1**	**D2**	**D3**	**D5**	**T8**	**D6**	**D7**	**D8**	**D9**
L1	0.99	-	-	-	-	-	-	-	-	-	-
L2	0.62	0.95	0.95	-	-	-	-	-	-	-	-
L3	0.95	0.89	0.89	0.94	-	-	-	-	-	-	-
L4	0.81	0.86	0.86	0.89	0.90	-	-	-	-	-	-
L5	0.97	0.84	0.84	0.98	0.98	-	-	-	-	-	-
L6	0.96	-	-	-	-	0.96	-	-	-	-	-
L7	0.62	-	-	-	-	0.65	0.72	0.72	-	-	-
L8	0.98	-	-	-	-	0.98	0.97	0.97	0.98	-	-
L9	0.80	-	-	-	-	0.85	0.81	0.81	0.80	0.75	-
L10	0.95	-	-	-	-	0.94	0.90	0.90	0.95	0.97	0.99
L11	0.94	-	-	-	-	0.93	0.95	0.95	0.94	0.92	0.91

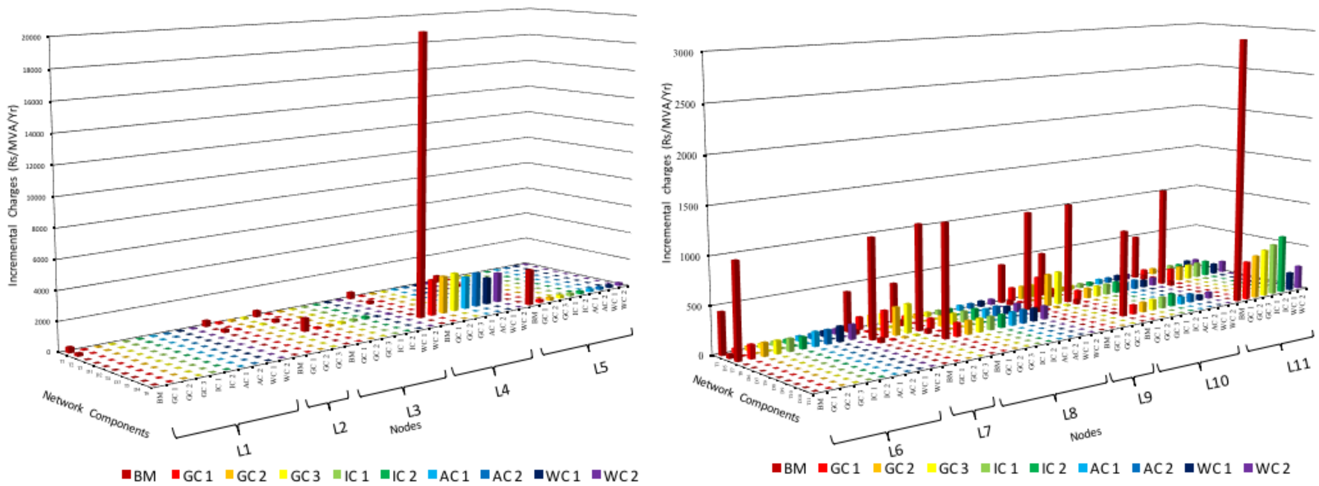
Further, coincident demands of load to the upstream asset are evaluated from (2). Using these coincident demands as input network data, AC power flow is performed to compute flows required for calculating unit charges. Line, bus, and transformer data for power flow analysis are given in the appendix. Discount rate and annuity factor of 6.9% and 7.4% are assumed respectively [23]. Load growth rate varies in the range of 0-3% [28]. Growth rates assumed for various customer sub-classes are given in Table II. For unit charges at all nodes, annualized incremental cost of all distribution network components are evaluated from (1)-(8) for customer sub-classes.

TABLE II

PERCENTAGE LOAD-GROWTH RATE FOR CUSTOMER CLASSES

Class	**Water Works**		**Agricultural**		**General**			**Industrial**	
Subclass	Class 1	Class 2	Class 1	Class 2	Class 1	Class 2	Class 3	Class 1	Class 2
% LGR	1	1.1	1.2	1.3	1.4	1.5	1.6	1.7	1.9

Incremental charges by customer sub-classes are shown in Fig. 5. Here component charges are shown with basic LRIC model, as well as for various sub-classes at all nodes with proposed model. Individual network component charges for the customer of different classes connected at nodes L1 to L5 are represented in Fig. 5(a), while that at nodes L6 to L11 are represented in Fig. 5(b). Basic LRIC model offers same incremental charges to each customer sub-class connected at a node, while proposed model offers different charges to each sub-class. The vertical axis of the plot represents incremental charges while the depth axis represents network components. Charges for each component by various sub-classes are shown in different colour. The horizontal axis shows customer sub-classes at the respective nodes. The first label of each nodal component, BM represents incremental charges from basic LRIC model. Depending on the customer sub-classes existing at each node, remaining labels of each nodal component are indicated by GC1, GC2, & GC3, IC1 & IC2, AC1 & AC2, and WC1 & WC2, representing various sub-classes of General, Industrial, Agricultural, and Water-Works classes respectively.



(a) At Nodes L1-L5

(b) At Nodes L6-L11

Fig. 5. Component incremental charges for customer sub-classes

As seen from Fig. 5(a), with the consideration of proposed model, a significant difference between charges is created at node L4, as compared to the basic model. This happens because network component T5 serving load at this node is highly utilized; hence high charges are applicable to accommodate any nodal increment. Also, charges for various sub-classes at all nodes consider LACF, hence are relatively lower than with BM. A similar difference can be visualized for nodes L6 to L11 in Fig. 5(b).

TABLE III

BRANCH INCREMENTAL CHARGES FOR NODE L8 (RS/MVA/YR)

		T1	D5	T8	D6	D7	T9
Water-Works	**Class 1**	62.32	3.07	83.01	5.02	0.37	141.39
	Class 2	59.76	3.66	92.27	5.16	0.43	145.61
Agricultural	**Class 1**	57.28	4.20	100.02	5.25	0.48	148.12
	Class 2	54.92	4.70	106.40	5.29	0.52	149.32
General	**Class 1**	52.68	5.14	111.59	5.30	0.56	149.54
	Class 2	50.58	5.53	115.75	5.28	0.59	149.03
	Class 3	48.60	5.87	119.02	5.24	0.61	147.98
Industrial	**Class 1**	46.76	6.16	121.54	5.19	0.64	146.53

	Class 2	43.42	6.63	124.79	5.06	0.67	142.82

For explanation, branch incremental charges calculated for every sub-class of customers connected at node L8 are shown in Table III. Charges for asset T8 and T9 are high, but minuscule for D7 used by all customer classes. This is because T8 and T9 are highly loaded, while D7 is lightly loaded. Another factor affecting charges for customer classes at any location is load growth rate. It can be seen in Table III that for components like T1 (with 91% loading), incremental charges decrease continuously as growth rate increases for various classes. For components like D5, T8, and D7 (with loading as 64.05%, 71.82%, and 68.11%, respectively), charges rise continuously with increase in growth rate. For components like D6 and T9 (with loading 81.52% and 81.44% respectively), charges increase with growth rate till it reaches 1.4%, after which they decline. As these charges are evaluated considering coincident demand in upstream asset usage, they reflect actual incremental cost due to a specific customer class. After computing annualized incremental cost for network components, unit LRIC charges are calculated at all nodes.

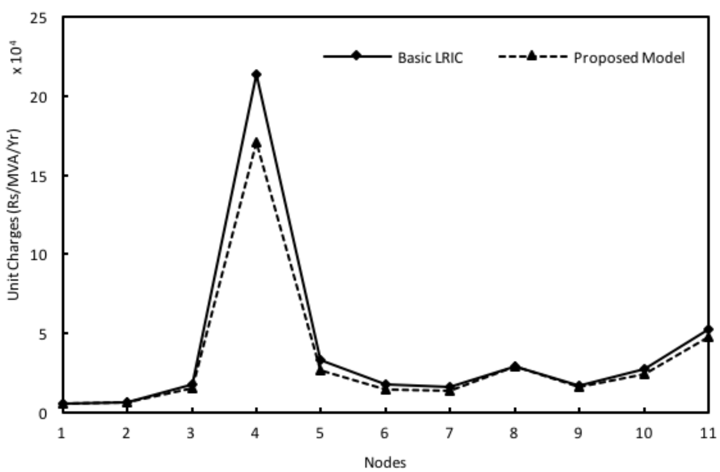


Fig. 6. Unit charges at all nodes

Unit charges computed from (9) are shown in Fig. 6. The impact of considering LACF in proposed approach vis-à-vis the traditional approach can be visualized as the difference between charges. Basic LRIC model reflects only distance and utilisation, whereas charges from the proposed model consider users' coincident demand on network usage, reflecting distance, utilisation of network component, and coincident peak usage of the asset by users. High charge at node 4 reflects that major network asset serving load at this node has low capacity to accommodate overall 0.1 MVA load increment.

TABLE IV

CONTRIBUTION FACTOR OF VARIOUS CUSTOMER CLASSES (CLCF)

	General			Industrial		Agricultural		Water Works	
Nodes	**Class 1**	**Class 2**	**Class 3**	**Class 1**	**Class 2**	**Class 1**	**Class 2**	**Class 1**	**Class 2**
L1	0.57	0.51	0.44	0.91	0.81	0.60	0.62	0.76	0.74
L2	0.86	0.80	0.73	-	-	-	-	-	-
L3	0.77	0.67	0.69	0.87	0.71	-	-	0.88	0.93

L4	0.71	0.85	0.73	-	-	0.59	0.77	0.79	0.82
L5	0.56	0.50	0.52	0.86	0.75	0.87	0.81	0.88	0.78
L6	0.55	0.53	0.57	0.87	0.84	0.83	0.86	0.75	0.82
L7	0.88	0.85	0.83	-	-	-	-	-	-
L8	0.77	0.79	0.67	0.68	0.81	0.69	0.74	0.70	0.57
L9	0.74	0.78	0.77	-	-	-	-	-	-
L10	0.47	0.53	0.48	0.81	0.89	0.87	0.90	0.69	0.78
L11	0.58	0.62	0.68	0.77	0.78	-	-	0.84	0.88

After computing unit charges, the contribution of specific class customers to total load is evaluated from (10), and shown in Table IV. This CLCF reflects the contribution of various customer sub-classes to the total load connected at any node. As seen from Table IV, sub-classes of General class have lowest while Industrial sub-classes have the highest contribution to the peak load of L1. Further sub-classes of Water-Works class have highest, and of General classes have the lowest contribution to the peak load of L11. Similarly, the contribution of various customer sub-classes in the total load connected at the nodes can be observed. This reflects customer class contribution to nodal peak loads, responsible for network reinforcement. Customer classes are charged only for part of load coinciding with peak nodal demand, and not for their maximum load. Due to this, charges with proposed model would be more cost-reflective than with traditional model.

TABLE V

TOTAL DUOS CHARGES (RS/YR) FOR VARIOUS CLASS CUSTOMERS

	General			**Industrial**		**Agricultural**		**Water-Works**	
Nodes	**Class 1**	**Class 2**	**Class 3**	**Class 1**	**Class 2**	**Class 1**	**Class 2**	**Class 1**	**Class 2**
L1	8194	4721	1389	44250	37905	5208	4161	5241	6205
L2	7997	4969	2965	-	-	-	-	-	-
L3	4658	2031	1609	9403	5337	-	-	6626	4495
L4	16697	58278	24822	-	-	14613	13117	19796	13935
L5	10874	13218	10951	34890	19821	22753	14964	20844	16514
L6	13070	19030	20358	39116	30330	25263	30877	27565	29574
L7	14484	23474	11492	-	-	-	-	-	-
L8	12541	13510	7720	140390	115885	4369	6364	16048	10521
L9	3083	3741	2462	-	-	-	-	-	-
L10	4008	6432	4658	16305	23907	11325	13129	11104	13357
L11	5892	4459	8083	10326	11194	-	-	13455	16877

Total DUoS charges for various class customers located at different nodes are given in Table V. Characteristics of individual customer class are considered to calculate total network charges with CLCF from (11). Customers are charged for network usage based on their contribution to nodal peak conditions. These charges with CF consideration reflect individual customer class contribution to network loadings.

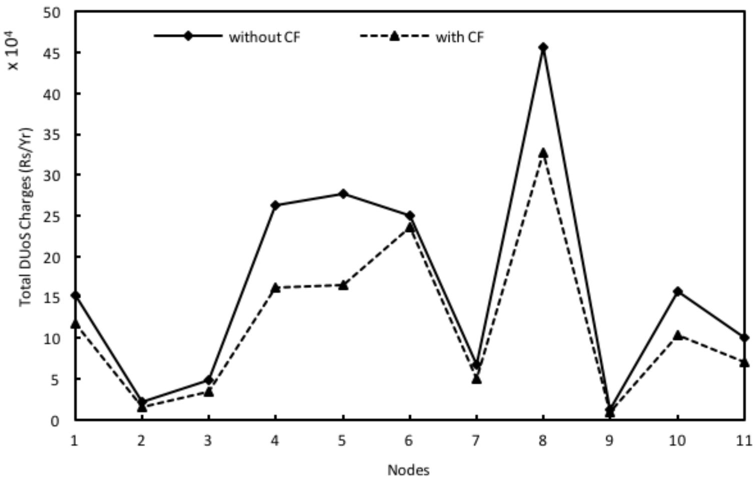


Fig. 7. Impact of CF on total DUoS charges

Total DUoS charges paid by users at different nodes with and without CF consideration are shown in Fig. 7. As can be seen, total charges paid by users connected at the nodes considering CF are lower than that without CF consideration. Charges are lower because consideration of coincident demand reduces future distribution network investment. DUoS charges without consideration of coincident demand reflect both distance and utilisation of distribution network components. These charges do not reflect actual network usage, and hence do not give users a pricing signal based on their load profile. Distribution network users are responsible for reinforcement of components when their imposed demand on network results in its full utilisation. Information about the timing of network peak usage is reflected in the electricity bill. Consideration of CF incentivizes users, by offering reduced charges for their low usage during network peaks. Hence, users are encouraged to improve their load profile and reduce their contribution to network peak. This results in lower total charges for users with CF consideration, as compared to the basic model which does not consider customer contributions. Modified load profile reduces network peaks, resulting in network reinforcement delay and investment deferral. Here, load profiles over the preceding year are used and updated every year. As the signal offered is based on a yearly profile, the customer response can be visualized as a composite load profile change over the following year.

C. Deferral in Network Investment

Annuitized PV of future reinforcement cost over all assets evaluated from (13) is shown in Fig. 8. Here, network component T1 and T8 have high annuitized PV. Investment for these components comes down significantly with the proposed pricing model. The proposed HCM approach offers lower annuitized PV for other components as well. Overall PV of future investment for all components with proposed pricing model and basic LRIC pricing model defers investment. Proposed pricing approach offers an investment reduction of £1359.54 per year, for the considered 22-bus system.

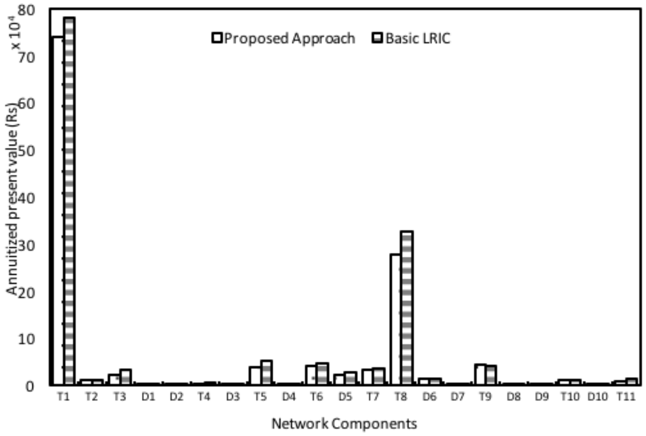


Fig. 8. Comparison of annuitized PV

IV. Conclusion

Existing DUoS charging approaches offer location-specific signal to customers and charge them based on their use-of-system. These approaches consider the load profile in conjunction with system's peak load, to calculate the component of network charges to be levied on a specific class. The calculations are based on measurements performed at system level, and not based on network flows in any upstream network. Thus, it does not offer a justifiable reflection of network usage, but just an assumed reflective usage. Also such models do not differentiate between various customer classes contributions to distribution network peak flow. This paper proposes a Hierarchical Contribution Factor based model to offer customer class-specific signal, along with a locational signal. This considers different customer class contributions to network peak demand using LACF and CLCF. CFs considered at two levels determines customer classes' effective contribution to asset reinforcements for evaluating distribution network prices. Proposed model provides a forward-looking economic signal, and thus encourages customer classes to improve their load profile and reduce their contribution to distribution network peaks. Price signals provided by this model are beneficial to both utility and users; users would be charged lower network charges and utility would defer network investment.

With increasing penetration of smart meters, this pricing model is likely to have a wider influence on the future network charging mechanisms. Major investment are being made world over, in smart meters and smart distribution management systems, with UK targeting a complete smart meter roll out at house hold level. As a general framework, smart meters could be used at multiple network levels to measure real-time power flow in networks at each level. With smart distribution management systems and embedded algorithms in place, information from each network level could be correlated and processed to assess any customer's contributions to upstream network asset's peak power flow at each level. These true network usage reflections could be translated into price signals representing network usage charges. This would offer an opportunity to assess a measured reflection of network usage, rather than an assumed network usage based on customer's peak load.

V. APPENDIX

TABLE VI

LINE DATA FOR 22-BUS PRACTICAL INDIAN NETWORK [42]

Line Name	Voltage (kV)	R (Ω)	X (Ω)	B (S)
D1	33	0.1026	0.1157	0.0000
D2	33	0.0181	0.0204	0.0000
D3	33	0.1346	0.1519	0.0000
D4	33	0.0385	0.0434	0.0000
D5	132	0.0241	0.0574	0.0066
D6	33	0.0468	0.0528	0.0000
D7	33	0.0103	0.0116	0.0000
D8	33	0.0385	0.0434	0.0000
D9	33	0.1167	0.1316	0.0000
D10	33	0.1408	0.1588	0.0000

TABLE VII

BUS DATA FOR 22-BUS PRACTICAL INDIAN NETWORK [42]

Bus Name	Voltage (kV)	Power Factor	Load (MVA)
L1	11	0.95	26.6
L2	33	0.96	3.15
L3	11	0.888	2.79
L4	11	0.928	1.23
L5	11	0.953	8.44
L6	11	0.921	17.58
L7	33	0.971	4.19
L8	11	0.91	15.7
L9	33	0.98	0.76
L10	11	0.903	5.68
L11	11	0.917	1.93

TABLE VIII

TRANSFORMER DATA FOR 22-BUS PRACTICAL INDIAN NETWORK [42]

Transformer Name	Voltage (kV)	Effective Z (Ω)
T1	220/132	0.0985
T2	132/11	0.284
T3	132/33	0.4096

T4	33/11	1.5
T5	33/11	3.625
T6	33/11	0.75
T7	132/11	0.6135
T8	132/33	0.2702
T9	33/11	0.3901
T10	33/11	0.8742

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